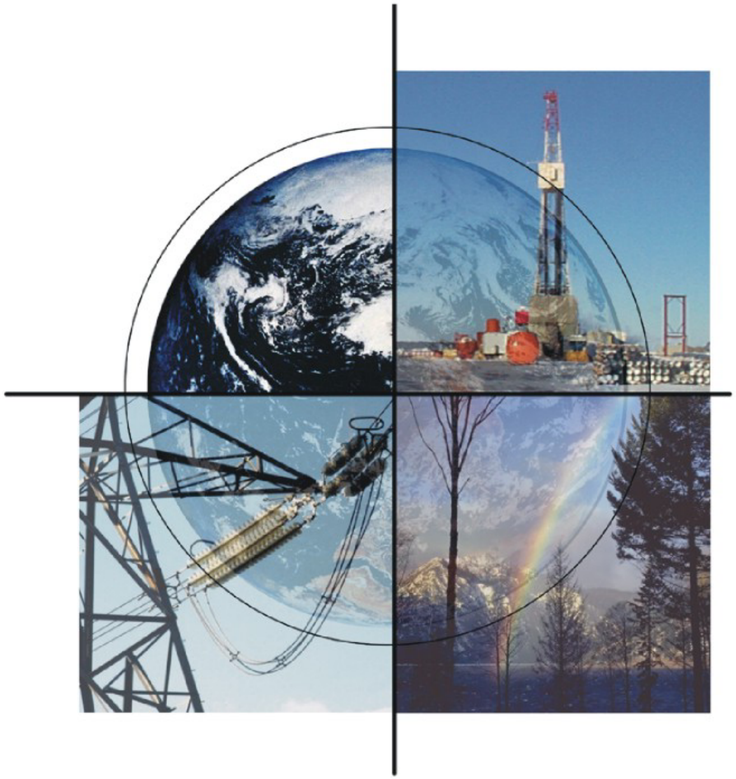
Systems Analysis of CO_2 Capture Concepts



Tom Tarka (Energetics)
Phil DiPietro (Energetics)
Jared Ciferno (NETL)

Presentation at the NETL Peer Review, 06/23/04

NETL

Goals and Objectives

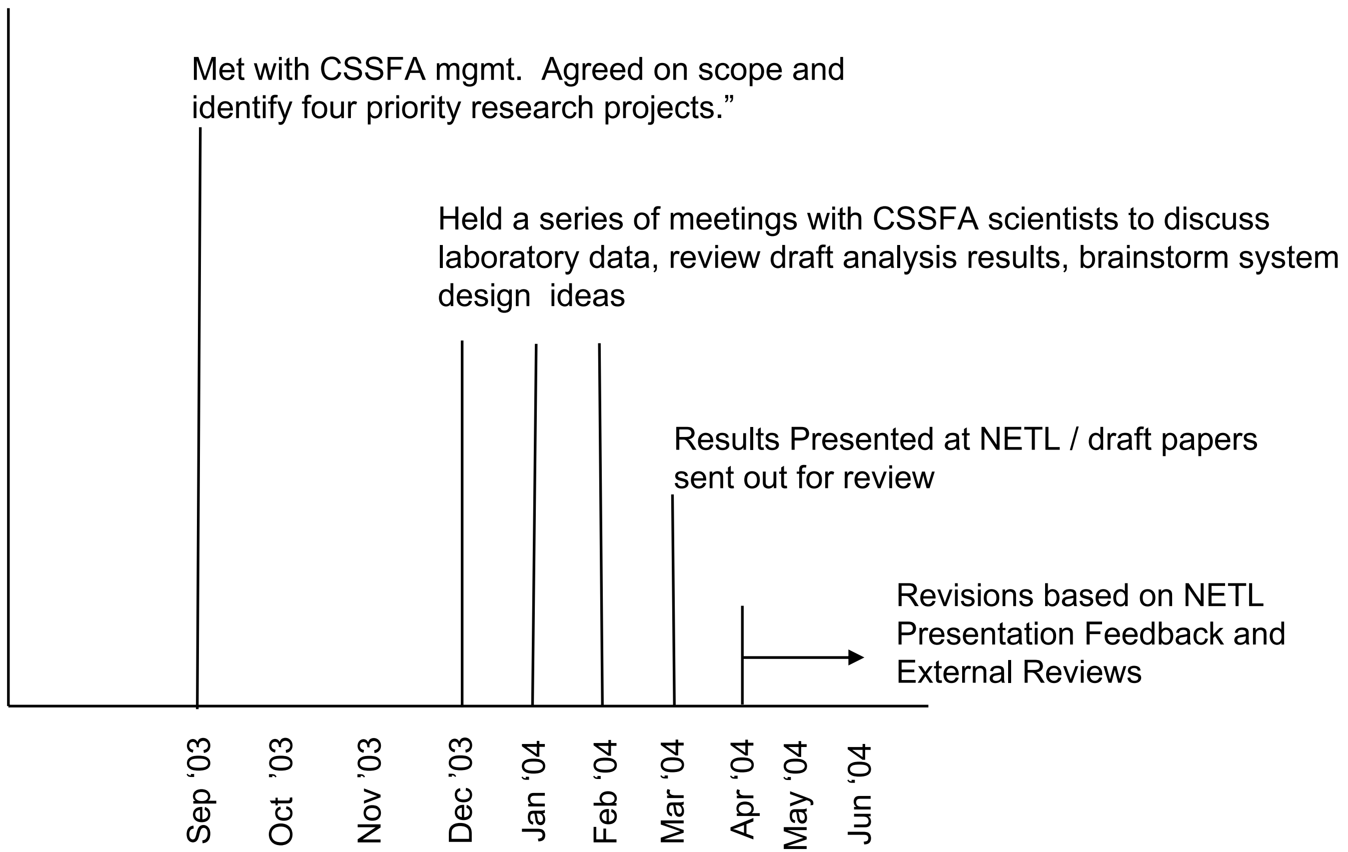
- Place R & D work in a systems context
- Assess potential of research projects to meet the program goals
- Craft a paper and presentation materials to summarize results and detail methodology

Scope of Work

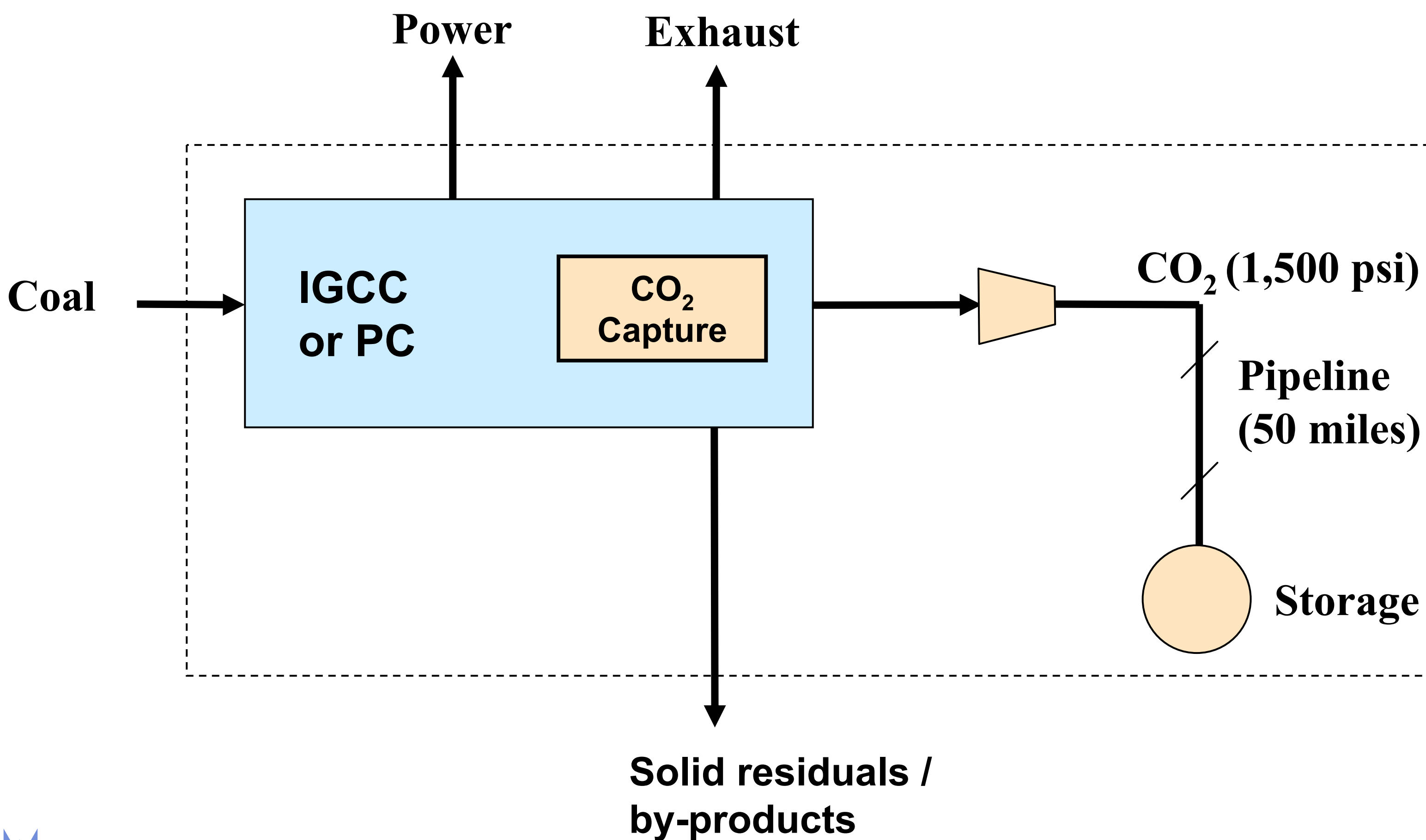
- **Assess four capture technologies in FY04**
  - Aqueous Ammonia
  - Organosilane hybrid membrane
  - Aminated Sorbents
  - Lithium sorbents

- **Level of effort is roughly 1.25 FTE**
  - 0.25 of Jared Ciferno
  - 0.25 of Phil DiPietro
  - 0.75 of Tom Tarka

Work Time Line



Analysis Boundary



Analysis Process

1. Interview researchers / review literature
2. Develop conceptual design(s)
3. Perform mass and energy balances to 400 MW net gen
4. Estimate equipment cost, system efficiency, and rates pollutant emission and by-product generation
5. Develop a cash flow model of a power plant with the capture system
6. Exercise the model to quantify sensitivities
7. Compare and contrast technology performance with
   - Base case power plant without capture
   - Base case power plant with commercially-available capture
8. Provide recommendations
9. Iterate with researchers, identify optimal systems design
10. Send vetted analysis for external review

Performance Metrics

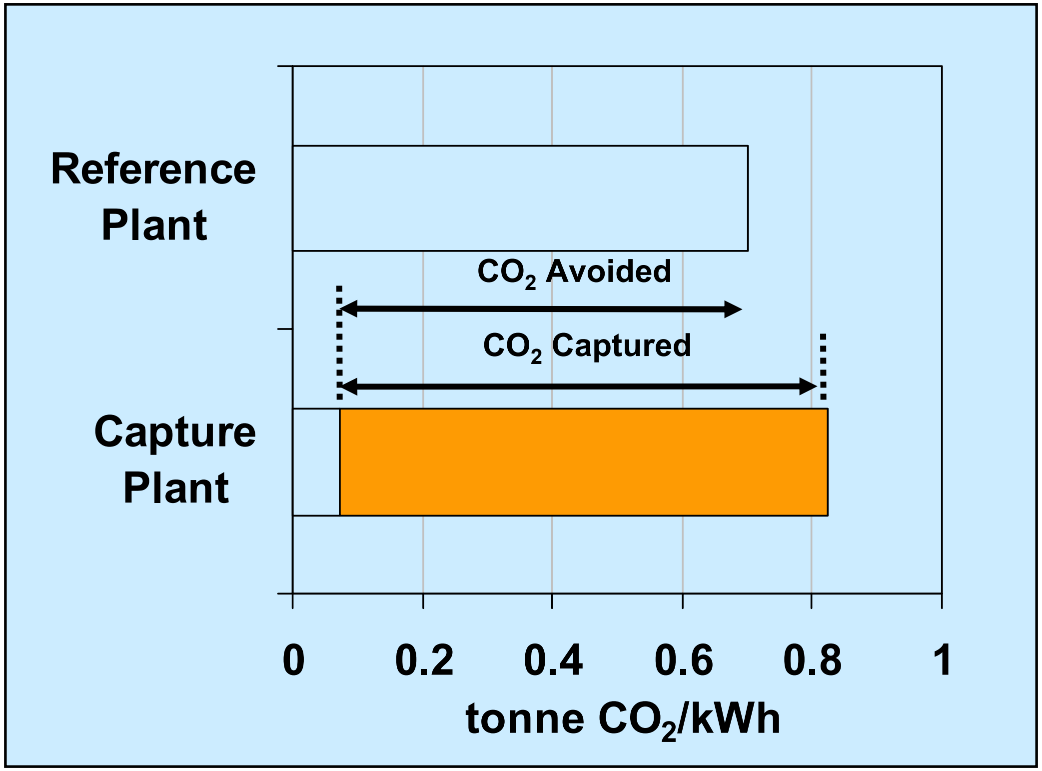
Cost of Avoided Emissions

ΔCOE / ΔCarbon Intensity

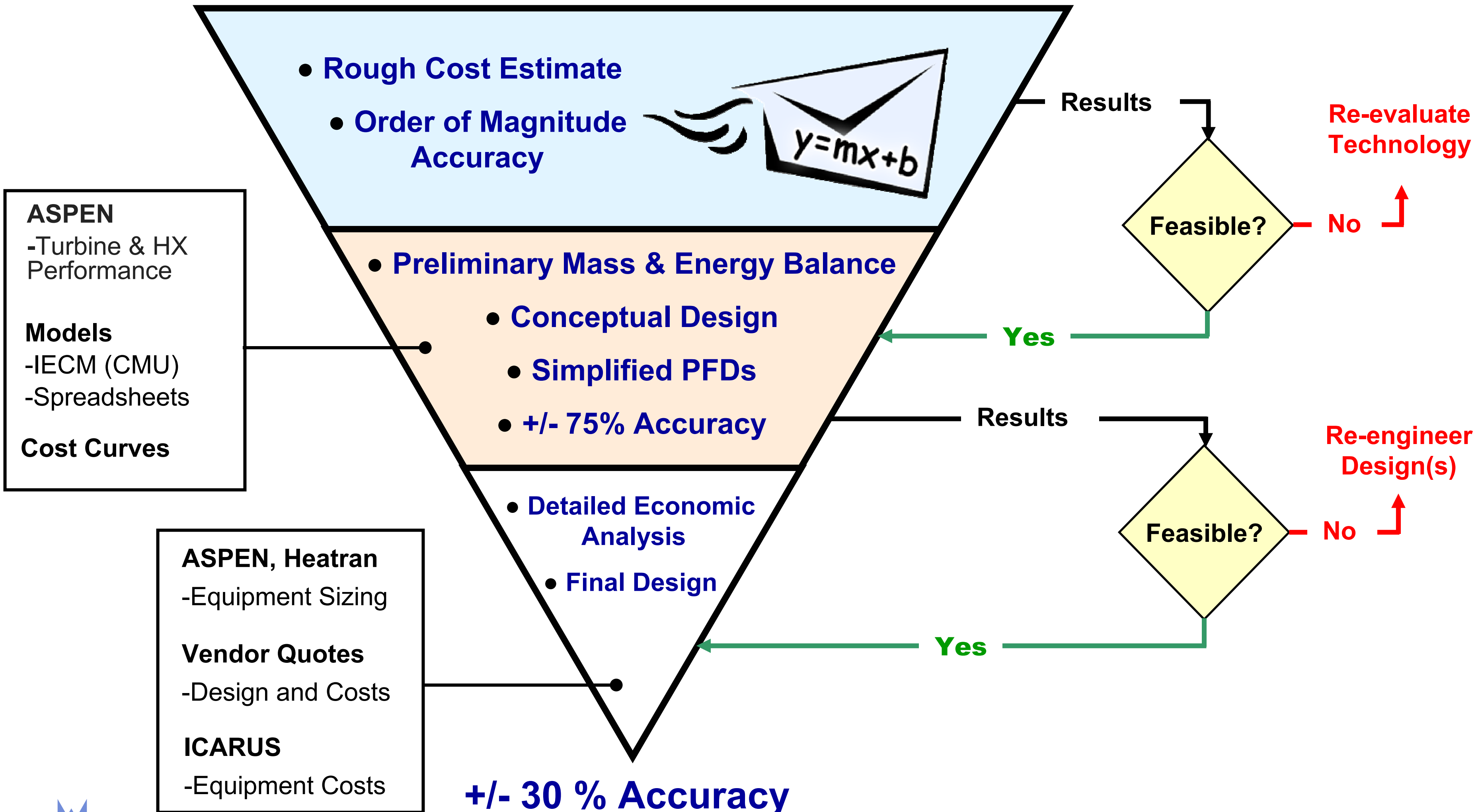
$$\frac{(c/kWh_{capture} - c/kWh_{base})}{(kgC/kWh_{base} - kgC/kWh_{capture})}$$

Percent increase in COE

$$(c/kWh_{capture} / c/kWh_{base}) - 1$$



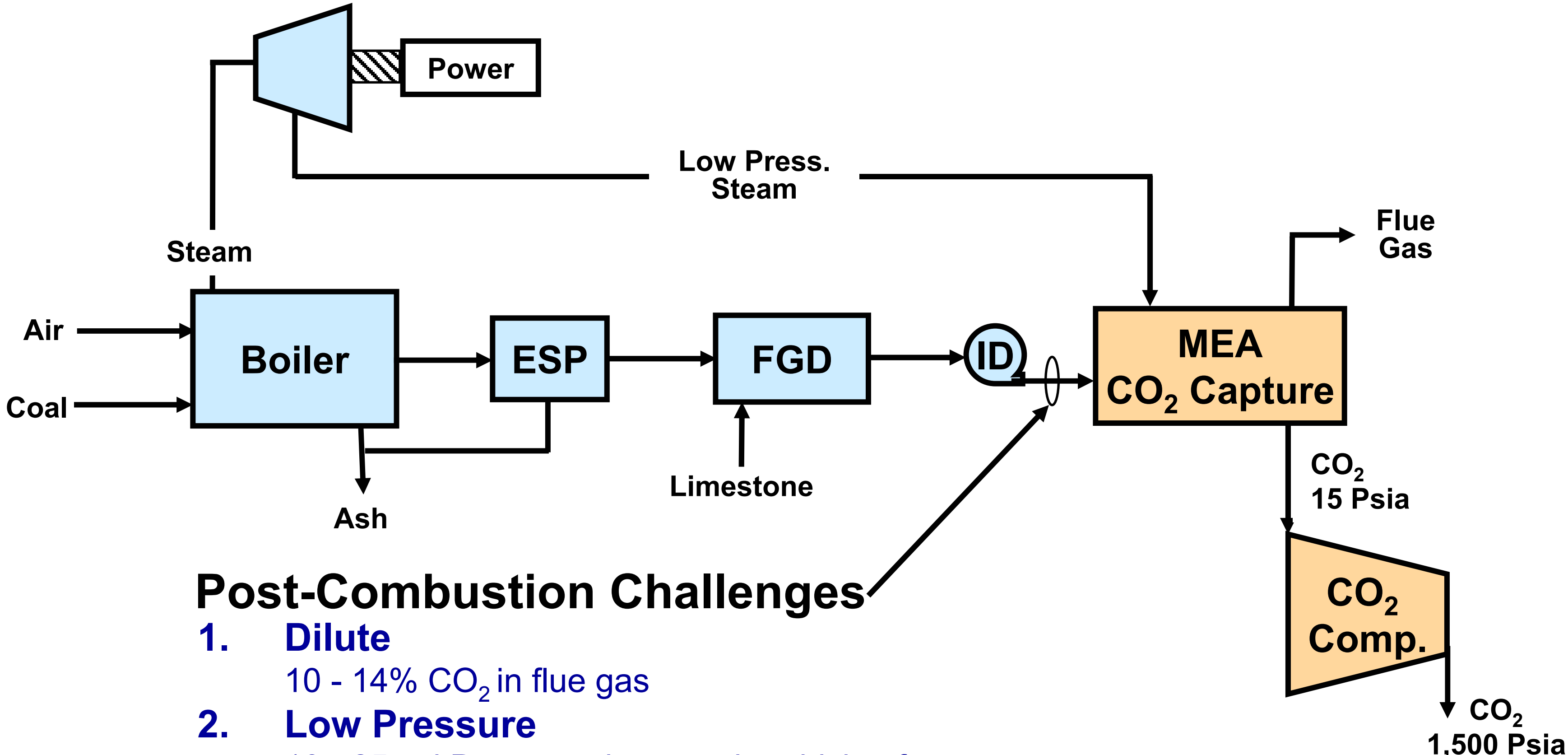
Approach



Rough Cost Estimate
Order of Magnitude Accuracy
y=mx+b
Results
Feasible?
No
Re-evaluate Technology
Yes
ASPEN
-Turbine & HX Performance
Models
-IECM (CMU)
-Spreadsheets
Cost Curves
Preliminary Mass & Energy Balance
Conceptual Design
Simplified PFDs
+/- 75% Accuracy
Results
Feasible?
No
Re-engineer Design(s)
Yes
Detailed Economic Analysis
Final Design
ASPEN, Heatran
-Equipment Sizing
Vendor Quotes
-Design and Costs
ICARUS
-Equipment Costs
+/- 30 % Accuracy

Pulverized Coal Base Case

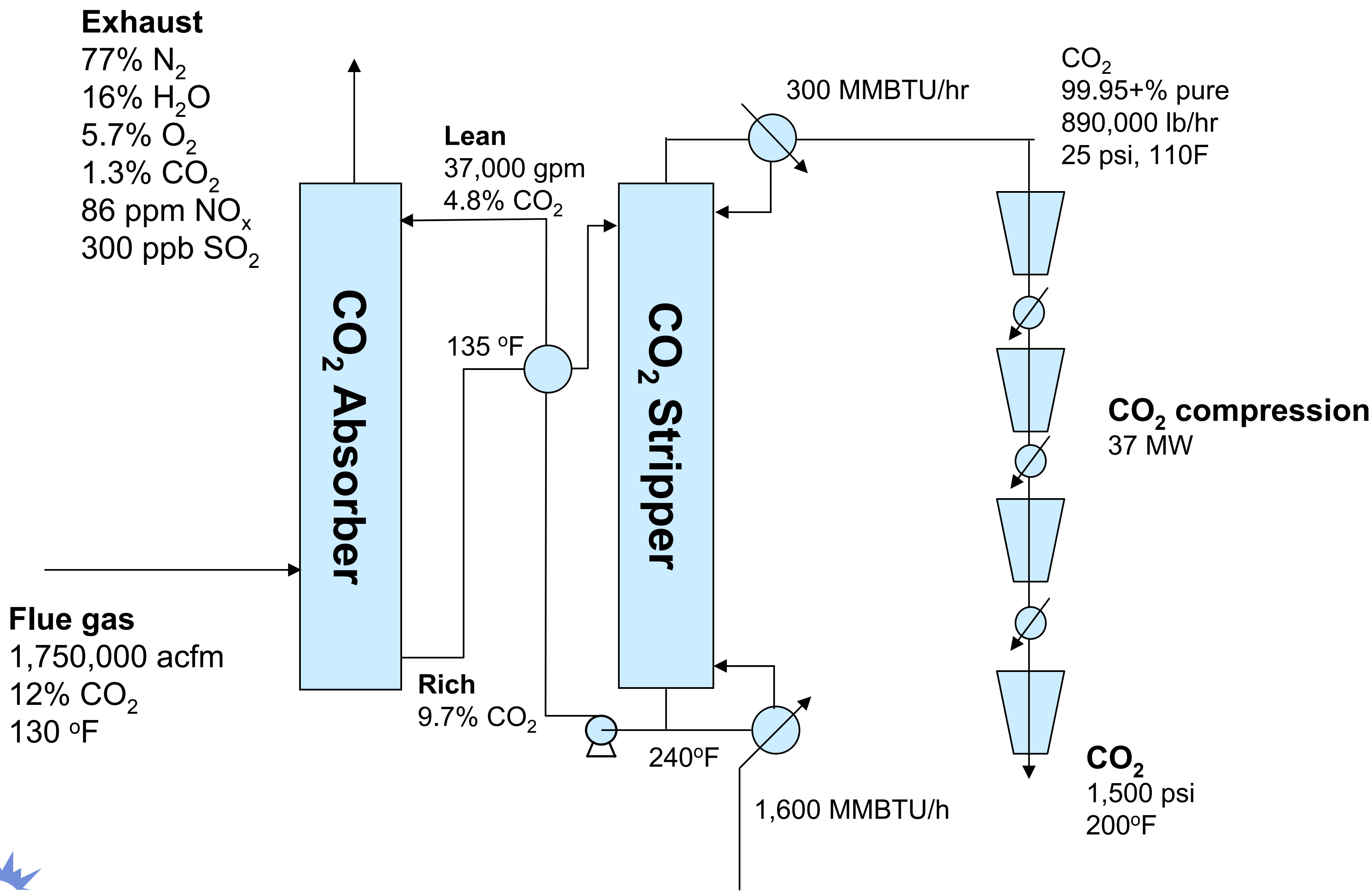
Post-Combustion Current Technology
Pulverized Coal Power Plant with CO_2 Scrubbing



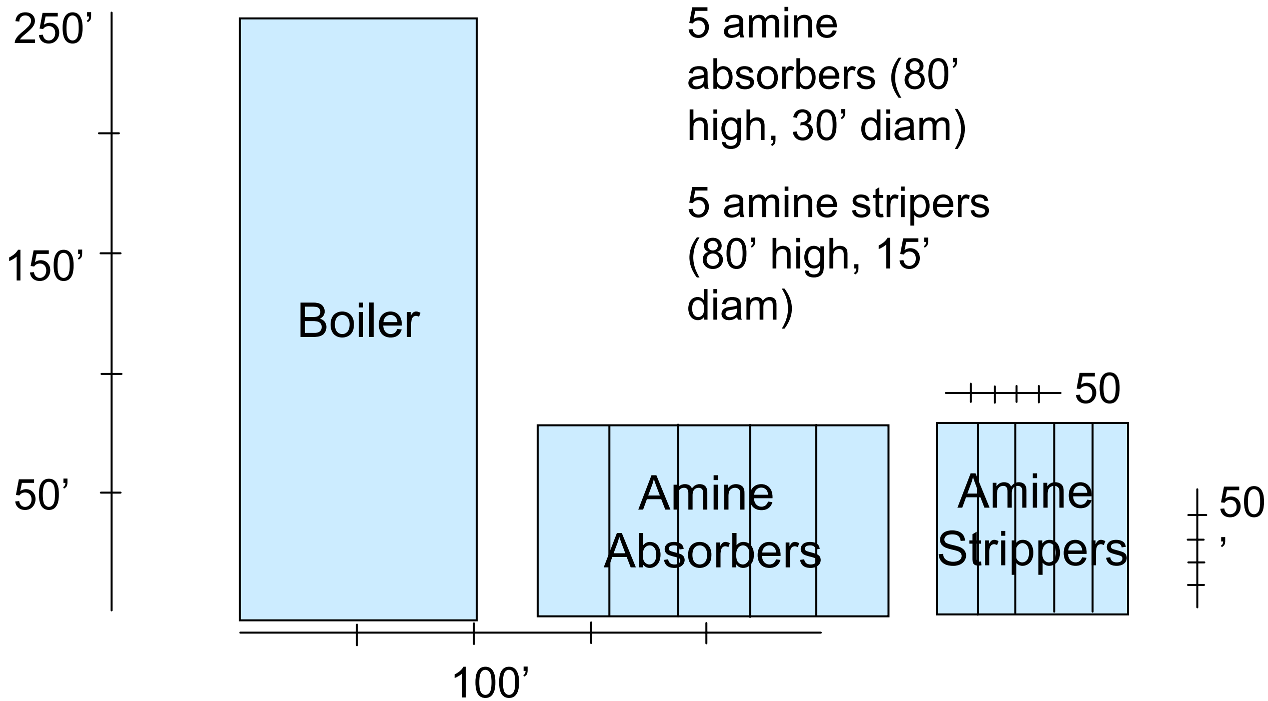
Post-Combustion Challenges

1. **Dilute**
   10 - 14% CO_2 in flue gas
2. **Low Pressure**
   10 - 25 psi Decreased separation driving force
3. **Contaminants**
   SO_2, SO_3, Particulates, etc.

Amine-based CO_2 Capture System



Amine Plant Size and Cost



5 amine absorbers (80’ high, 30’ diam)

5 amine stripers (80’ high, 15’ diam)

Absorber size, cost

f (acfm flue gas, % capture)

Stripper size, cost

f (amine flow rate)

Solution pump load

f (amine flow rate)

Amine make-up cost

- **5 kg MEA / mt CO_2 absorbed**
  - General loss: 1.6 kg MEA/mt CO_2
  - SO_x loss: 2 mole MEA/mole SO_x in absorber inlet
- **Amine cost $1.50 per kg**
  - Econoamine, includes inhibitor cost
- **Cost equals 7.5 $/mt CO_2 captured**
  - 5 kg MEA / mt CO_2 * $1.50/kg MEA

Amine make-up rate from "recovery of CO_2 from flue gases: Commercial Trends, G. Chapel, C. Mariz, J. Ernst, 1999;

PC Base Case Economic Results

	No CO_2 Capture	Amine Capture
Gross Power (MW)	425	503
Heat Rate (Btu/kWh)	8,500	9,900
$/kW (equipment)	1,100	1,900
$/kW (contingency)	400	700
COE (cents/kWh)	4.9	9.0
CO_2 intensity (kg/kWh)	0.76	0.112
% increase in COE	N/A	84%
Avoided cost ($/mt$CO_2$)	N/A	63

Aqueous Ammonia for CO_2 Capture

Use of Aqueous Ammonia for SO_2 Capture is a Commercially Available Technology

- **ALSTOM Power offers Ammonia Scrubbing as one of its SO_2 compliance options**
  - 130 MW demonstration at First Energy's Niles plant in Ohio
  - By-product revenue drive economics
- **Idea for this project is to add CO_2 capture**

	Limestone Scrubber	Aqueous Ammonia
Parasitic Load (MW)	4-7	0.2
Reactant cost ($/ ton SO_2)	22	109
By-product revenue ($/ton SO_2)	0	217
Net material revenue ($/ton SO_2)	(22)	+108
Limestone 15 $/ton, anhydrous ammonia 200 $/ton, no pay market for FGD sludge, ammonia sulfate 105 $/ton		

Aqueous Ammonia for CO_2 Capture from PC Power Plants

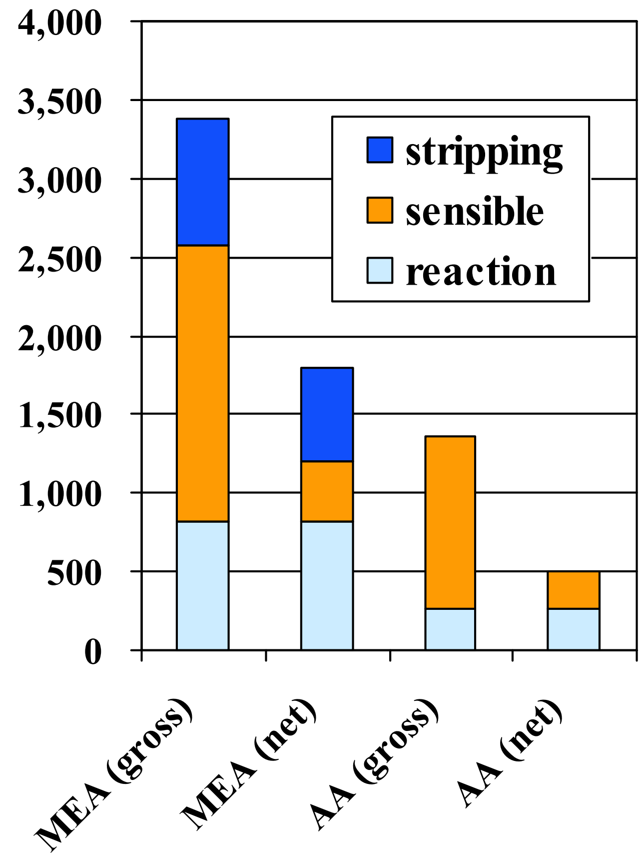
Similar to aqueous amines (liquid chemical absorbent that uses steam to regenerate) with 4 hooks

1. Reduced steam load
2. More concentrated CO_2 carrier
3. Lower-cost chemical
4. Multi-pollutant control with salable by-products

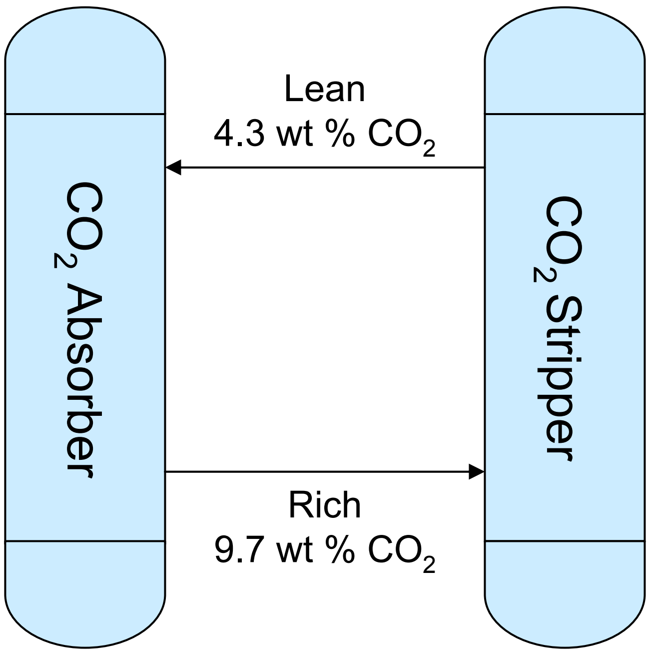
Hook 1: Reduced Steam Load

$$Q_{regen} = Q_{rxn} + Q_{sensible} + Q_{strip}$$

- **Q reaction**
  - MEA: 825 BTU/lb CO_2 captured
  - AA: 262 Btu/lb CO_2 (carbonate/bicarb)
- **Q sensible**
  - MEA: (135F-240F)*18.5 lbs sol./lb CO_2 * 0.9 Btu/lbF = 1,750 Btu/lb CO_2
  - AA: (80F) * 14.7 lbs sol/lb CO_2 * 0.9 Btu/lbF = 1,100 Btu/lb CO_2
- **Q stripping**
  - MEA: 800 Btu/lb CO_2 (1 mole steam per mole CO_2)
  - AA: assume no stripping steam required



Hook 2: Reduced sorbent solution flowrate



Δ 5.4 wt % CO_2

Laboratory results indicate

Aqueous Ammonia can

achieve a loading difference of 6.8 wt % CO_2

- reduces stripper cost from 36.4 to 25.2 MM$
- reduced circulation pump load from 1.8 to 1.2

MEA Solution flowrate $= \dfrac{12{,}000 \text{ ton CO2/day}}{.054} = 220{,}000$ ton/day

Hook 3: Lower cost chemical

- Cost of MEA
  - $1.50/kg MEA * 0.3 kg MEA/kg soln. * 18.5 kg soln./kg CO_2

  = **$8.33 / kg CO_2 carrying capacity**

- Cost of Ammonia*
  - $0.20/kg Amm. * 0.15 kg Amm/kg soln. * 14.7 kg soln./kg CO_2

  = **$0.44/kg CO_2 carrying capacity**

* Annhydrous Ammonia cost, cost of aqueous ammonia is roughly 4x. Cost of bicarbonate 30% increase

Chemical Make-up cost

- AA loss: 4.4 kg AA / mt CO_2
  - General use: 2 kg AA / mt CO_2
    - Conservatively high based on amine heuristic
  - SO_2: 2.4 kg AA / mt CO_2
    - 2 NH_3/SO_2 --- 34/64, 0.53 tons Ammonia / tons SO_2
    - (1.33 + 0.046)mt SO_2 / 400 MWh *1,000 kg SO_2/mt = 0.00344 kg SO_2/kWh (CO_2 absorber inlet)
    - 0.00344 kg SO_2/kWh * 0.53 kg AA/kg SO_2 * 1kWh/(1.7 lbs CO_2 /2200 lbs/mt) = 2.4 kg AA / mt CO_2

- AA makeup cost: $0.88 / mt CO_2 captured
    - $0.20/kg AA * 4.4 kg AA/mt CO_2 = $ 0.88 mt CO_2

- Low compared to MEA cost of $7.5 / mt CO_2

Hook 4: Value-added by products

- SO_2 → $(NH_4)2SO_4$ (Ammonium Sulfate Fertilizer)
- NO_x → $(NH_4)NO_3$ (Ammonium Nitrate Fertilizer)
- Hg → oxidized solid

By-product Revenues Summary Table

	Production Rate (lb/kWh)	Value ($/ton)	Op. cost ($/ton)	Op. revenue ($/ton)	Norm. Rev. ($/ton CO_2)
Mercury	7×10^{-8}	1.2×10^{8}	0	1.2×10^{8}	4.9
Ammonium Nitrate	0.010	155	218	(62.5)	(.36)
Ammonium Sulfate	0.068	105	51	54	2.9*
CO_2	1.7	--	--	--	--

*Includes value of avoided parasitic load from the limestone scrubber of 4 MW ($ 0.81/ton CO_2)

Ammonium Sulfate

Data

- Ammonia cost, 200 $/ton (Anhydrous, Chemical Marketing Reporter)
- Market value of ammonium sulfate, 105 $/ton (Chemical Marketing Reporter)
- 2.5 wt% sulfur in coal, heat content 12,760 Btu/lb
- 8,500 Btu/lb heat rate
- $SO_2 + 2NH_3 + \frac{1}{2} O_2 + H_2O \rightarrow (NH_4)_2SO_4$
- 5 MW load associated with a limestone scrubber for a 400 MW PC power plant

Calculations

- Ammonia use: 2 NH_3/SO_2 --- 34/64, 0.53 tons Ammonia / tons SO_2
- Fertilizer generation rate: SO_2 / $(NH_4)2SO_4$ -- 64/132 = 0.485 ton SO_2 / ton fertilizer
- Fertilizer feedstock cost: 200 $/ton Amm * 0.53 Amm/$SO_2$ * 0.485 SO_2/fertilizer = 51.4 $/ton
- Fertilizer operating revenue: 105-51.4, 53.6 $/ton fertilizer
- (8,500 Btu/kWh / 12,760 Btu/lb) * 0.025 lbS/lb coal * 2 lb SO_2/lb S = 0.033 lb SO_2/kWh
- (8,500 Btu/KWh / 12,760 Btu/lb) * 0.71 lbC/lb coal * 3.67 lb CO_2/lb C = 1.73 lb CO_2/kWh
- 0.033 lb SO_2/kWh / 0.485 lbs SO_2/lb fertilizer= 0.068 lbs fertilizer generated per kWh
- $53.6 /ton fertilizer * (.068/1.73) = **$ 2.1 of fertilizer revenue per ton CO_2**
- (5/400) kWh/kWh * $0.05/kWh * 1 kWh/(1.7 lbs CO_2 * 2000 lbs/ton) = $0.81 / ton$CO_2$

Ammonium Nitrate

Data

- Ammonia cost, 200 \$/ton (Anhydrous, Chemical marketing Reporter)
- Market value of ammonium nitrate, 155 \$/ton (Chemical Marketing Reporter)
- Ozone cost: 450 \$/ton
- NOx -> NO_3; $NO_3 + NH_4 \rightarrow (NH_4)NO_3$

Calculations

- Ammonia use: NH_4/NO --- 18/30, 0.6 tons Ammonia / tons NO_x
- Fertilizer generation rate: NO_x / $(NH_4)NO_3$ -- 30/80 = 0.375 ton NO_x / ton fertilizer
- Fertilizer feedstock cost: 200 \$/ton Amm * 0.6 Amm/NO_x * 0.375 NO_x/fertilizer = 45 \$/ton
- Ozone feedstock cost: \$460/ton NO_x * (30/80) = 172.5 \$/ton fertilizer

- Fertilizer operating revenue: 155- (45+172.5) = -62.5 \$/ton fertilizer
- (8,500 Btu/KWh / 12,760 Btu/lb) * 0.71 lbC/lb coal * 3.67 lb CO_2/lb C = 1.73 lb CO_2/kWh
- 0.0038 lb NO_x/kWh / 0.375 lbs SO_2/lb fertilizer= 0.010 lbs fertilizer generated per kWh

- (\$62.5)/ton fertilizer * (.010/1.73) = **(\$ 0.36) fertilizer revenue per ton CO_2**

Mercury

Data:
- 8.2 lbs mercury per trillion Btu coal (0.2 lbs Hg per thousand short tons of coal)*
- Estimated value of mercury emissions reduction: 60,000 $/lb Hg [FE website]

Calculations:
- Mercury generation rate: (8,500 Btu/KWh * 8.2 lbs Hg /10^12 Btu coal = 7 x 10^{-8} lb Hg/kWh
- 60,000 $/lb * 7 x 10^{-8} lb Hg/kWh = $0.0042 $/kWh
- $0.0042/kWh * 1 kWh / 1.7 lbs CO_2 * 2000 lb /ton = 4.9 $/ton CO_2

* EIA, "Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants: Sulfur Dioxide, Nitrogen Oxides, Carbon Dioxide, and Mercury and a Renewable Portfolio Standard, July 2001

Ammonia Sulfate Market Size

	Million tons per year
Ammonia sulfate generated from one 400 MW PC power plant (2.5% S coal)	.073
Current domestic market for ammonium sulfate	2
Current world demand for nitrogen fertilizer	83

(9,100 Btu/kWh / 12,760 Btu/lb) * 0.025 lbS/lb coal * (114/32 lbs AS/lb S) = 0.064 lbs AS/kWh

400,000 kW * (0.65 *8,760) hr/yr * 0.064 lbs AS/kWh *0.0005 tons/lb = 73,000 tons AS/yr

Metric	Base	Amine	AA (CO_2 only)	AA (CO_2 and SO_2)	AA (CO_2, SO_2, NO_x, Hg)
Boiler turbine cap cost, \$/kW	830	830	830	830	830
Gross Power, MW	425	503	494	492	492
CO_2 capture cap cost, \$/kg CO_2/hr	N/A	350	320	320	320
Steam to CO_2 rec. (Btu/ kg CO_2)		6,000	1,700	1,700	1,700
CO_2 comp. load (kWh/kg CO_2)		0.15	0.14	0.14	0.14
By-product revenue, cents/kWh		0	0	0.36	0.81
Percent increase in COE		84	50	31	21
Capture cost per mt CO_2 avoided		63	37	28	21

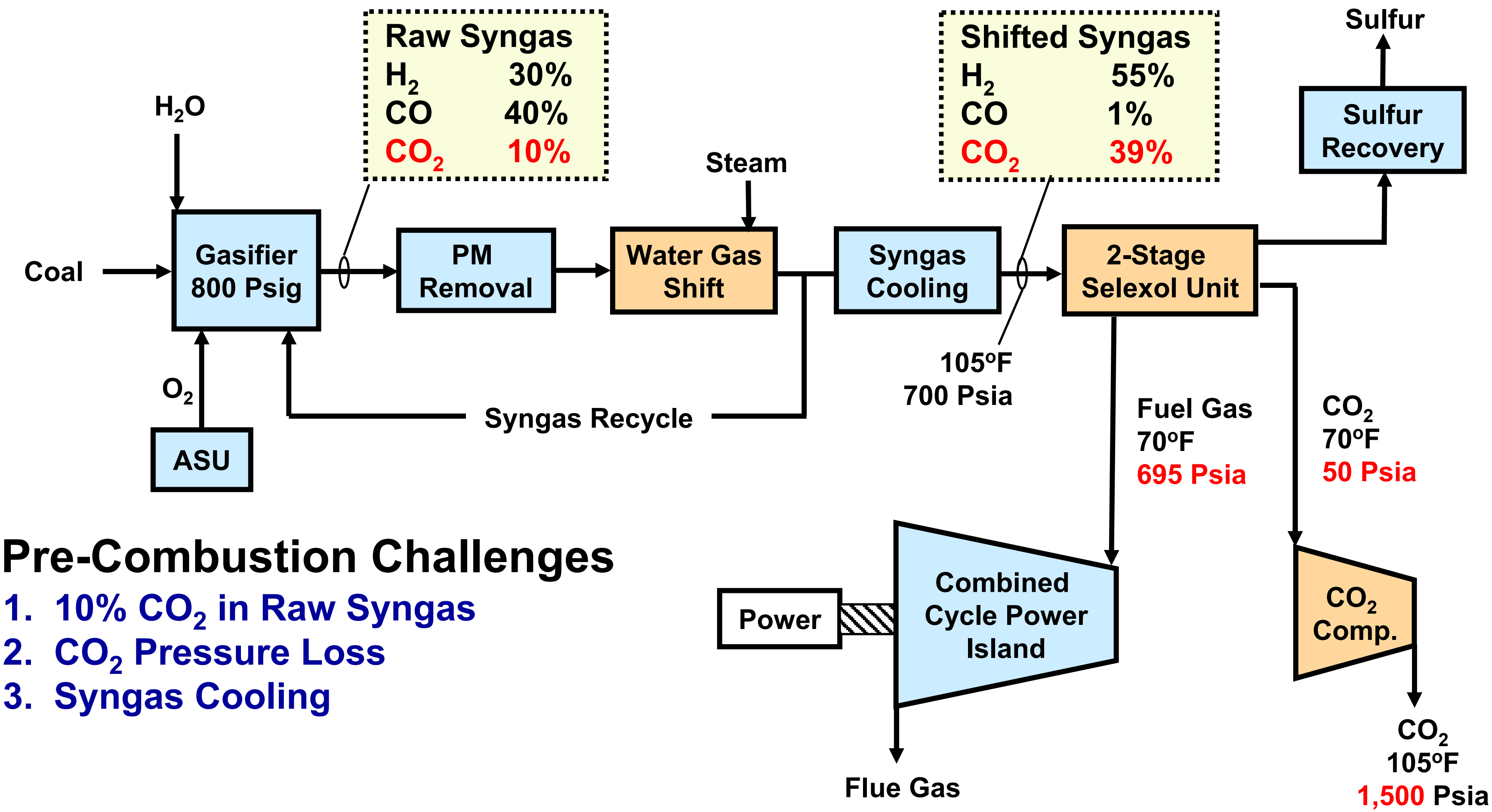
Future Analysis Work for this Technology

- More rigorous market study of ammonia sulfate/nitrate
  - International markets
  - Competing commodities,
  - Reliance on natural gas
- Evaluate trade-offs between absorption/desorption temperatures and CO_2 transfer capacity
  - Possible need for flue gas cooling
- Closer look at ammonia slip
  - Tailgas cleanup / guard options
  - Use of bicarbonate as feedstock
- Closer look at heat integration and stripping steam requirements

CO_2 Capture from IGCC Base Case

Pre-Combustion Current Technology

IGCC Power Plant with CO_2 Scrubbing

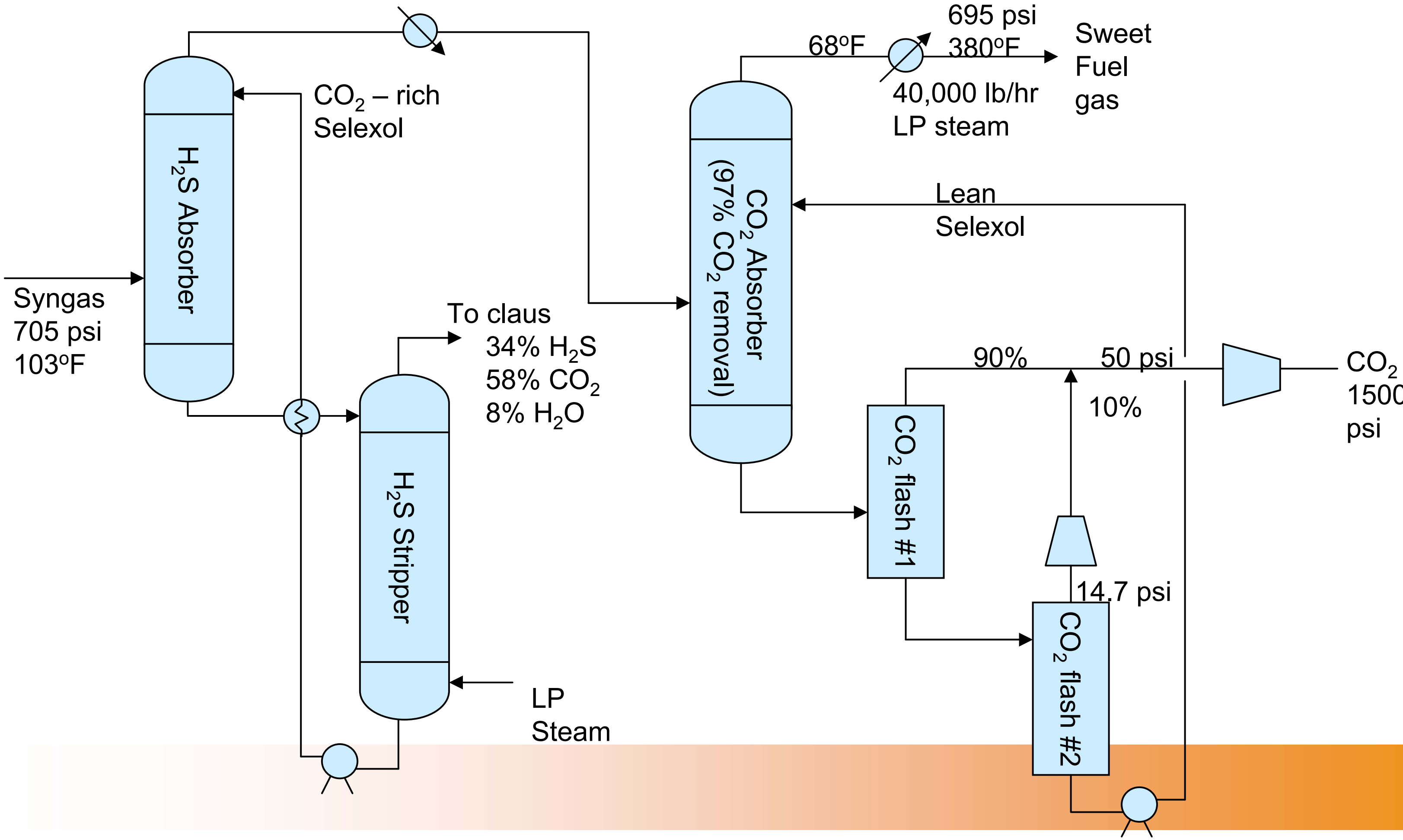


Pre-Combustion Challenges

1. 10% CO_2 in Raw Syngas
2. CO_2 Pressure Loss
3. Syngas Cooling

Source: *Evaluation of Innovative Fossil Fuel Power Plants with CO2 Removal*, DOE/EPRI, 1000316

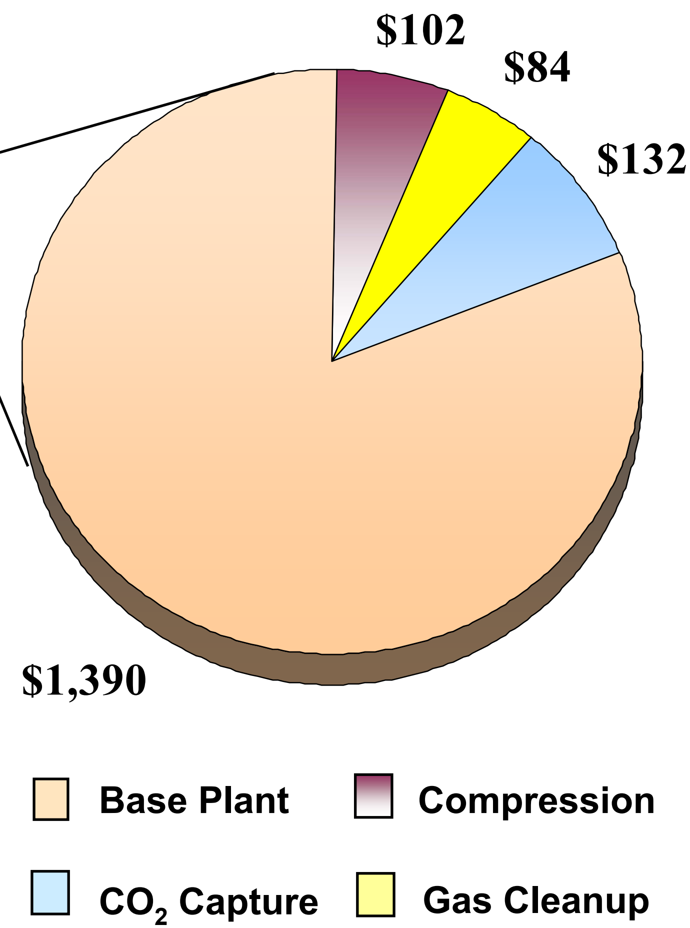
Selexol combined H_2S/CO_2 capture system, simplified PFD



IGCC with CO_2 Capture Base Case Results

	No Capture	Capture
Total Power Plant Capital ($/kWh)	1,430	1,707
Capital COE (c/kWh)	3.73	4.43
Variable COE (c/kWh)	1.78	2.07
Total COE (c/kWh)	5.51	6.50
Including Transportation and Storage		
Total Capital ($/kWh)	1,430	1,838
Total $/tonne CO_2 avoided	-	23.30
Total Sequestration COE (c/kWh)	-	6.87
Increase in COE (%)	-	25%
*No Capture Case Includes MDEA H2S Removal		

Based On: 1,500Ft Saline Aquifer, Levelized COE 15%, 65% Capacity Factor, 50 Mile Pipeline, 2002 Dollars



Membrane CO_2 capture

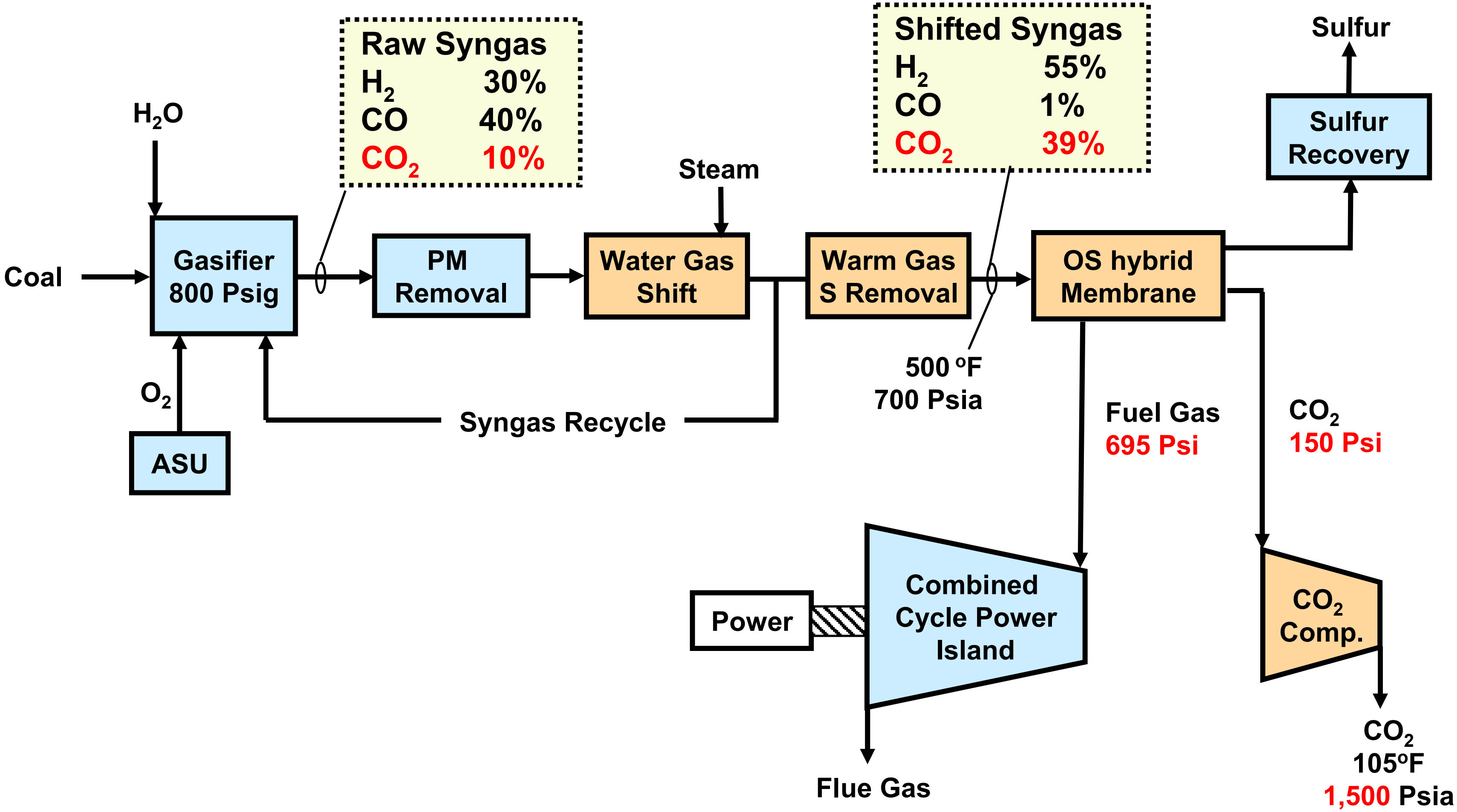
Hybrid Membrane for CO_2 Separation in IGCC Power Plants

1. **Trade-off between reduced CO_2 compression load and H_2 product loss**
   - CO_2 exits separator at **150** psi compared to **50** psi for Selexol,
   - but up to 5% of hydrogen product is lost through the membrane

2. **Linked with warm gas SO_2 capture, can avoid cooling and reheating fuel gas**
   - Membrane stable between 300-570°F

3. **Reduced operating & maintenance costs associated with membranes versus liquid circulation**

IGCC with Membrane CO2 Capture



More Detailed Look at the Membrane

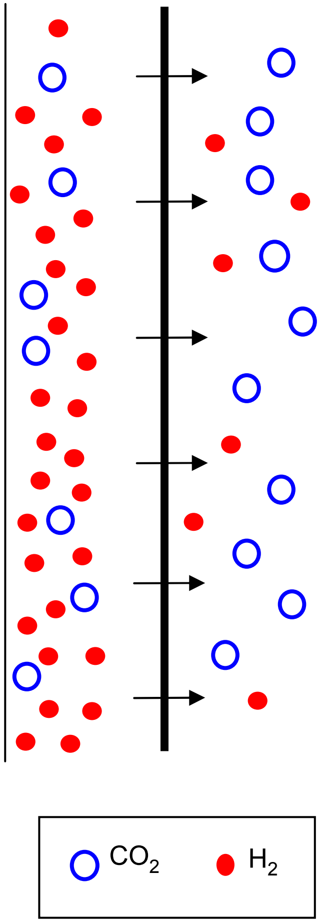
Selectivity – ratio of permeances (P)

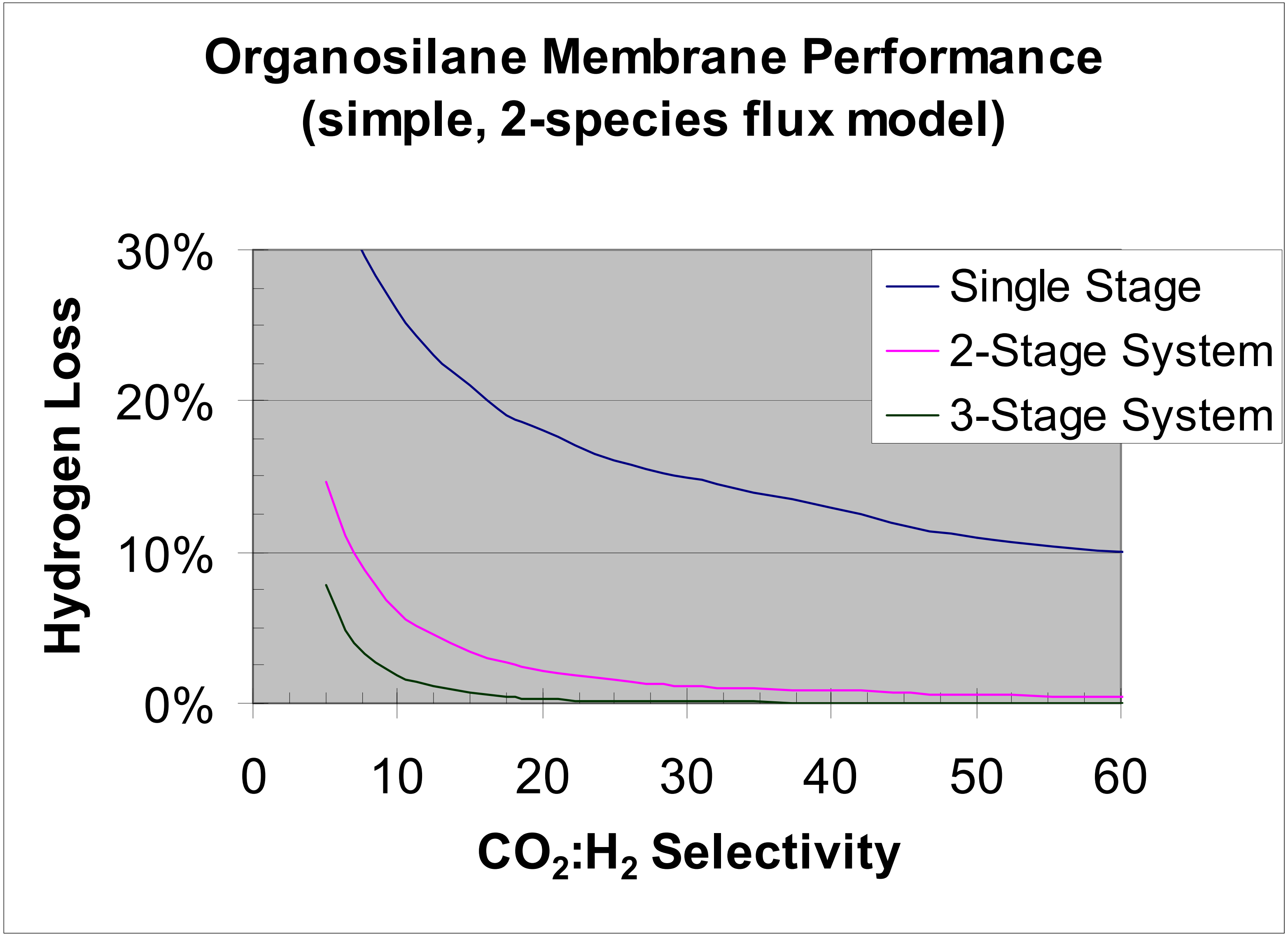
This case is reverse selectivity

$P_{CO_2} / P_{H_2} > 1$

The CO_2 product is the permeate

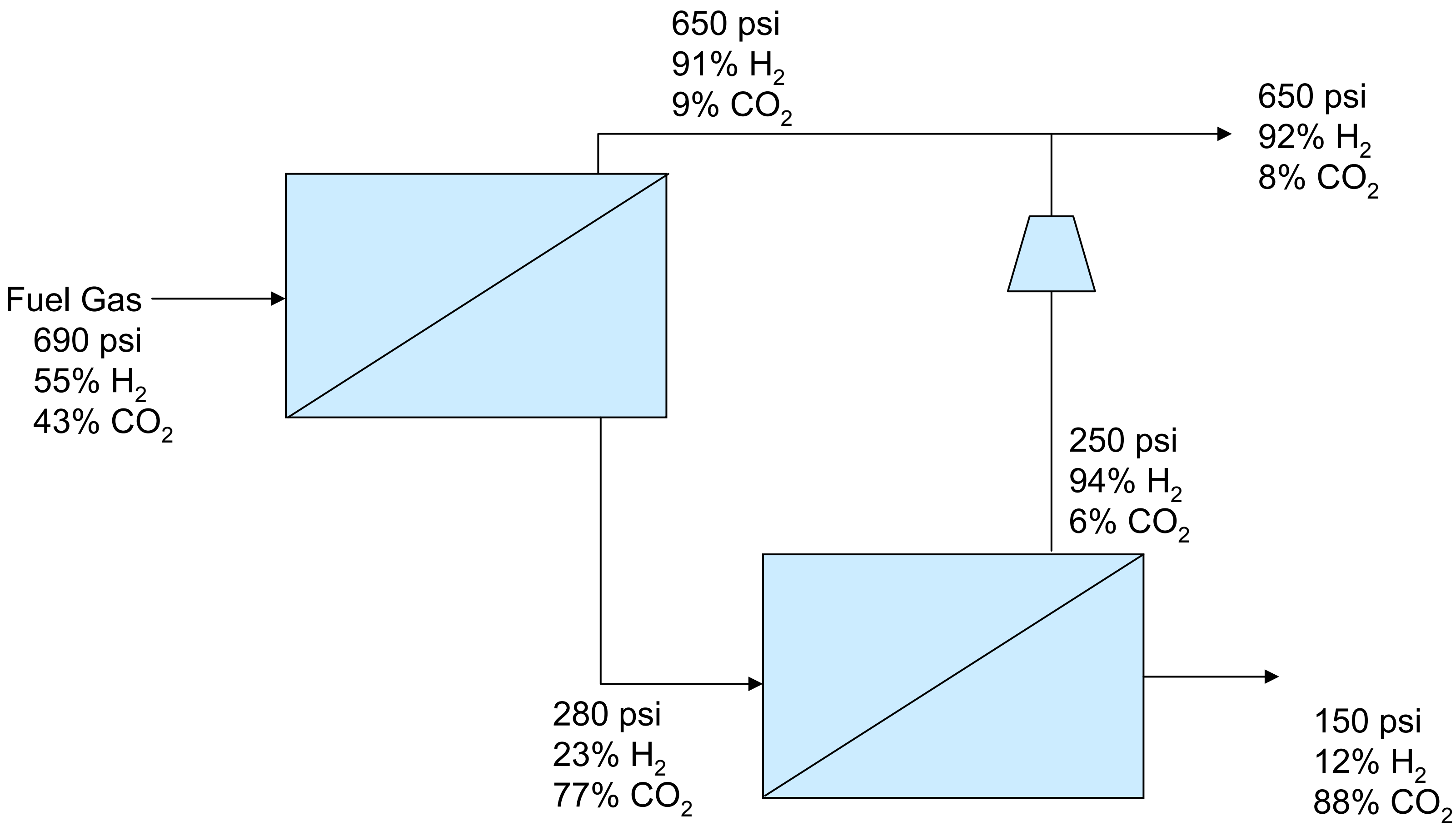
Molar flux = Permeance$_n$ · Δpp$_n$





Organosilane Membrane Performance
(simple, 2-species flux model)
30%
20%
10%
0%
Hydrogen Loss
0
10
20
30
40
50
60
CO_2:H_2 Selectivity
Single Stage
2-Stage System
3-Stage System

2-stage membrane separation process 13:1 selectivity



Assumptions for Membrane Systems Analysis

- CO_2 / H_2 Selectivty, 13:1
- Membrane cost, 400 \$/m^2
- Membrane life, 2 years
- Maximum trans-membrane pressure difference 400 psi

Future Work for the Organosilane Membrane Project

- Increment membrane model
- More rigorous model of warm sulfur removal
- Identify technology for recovery of residual H_2
- Explore niche applications

Future Work

- **Finish current analyses**
  - AA (abosrption temp, ammonia slip, mercury)
  - Membrane (warm S, increment model, pp driver)
  - Aminated sorbent (pressure drop, kinetics)
  - Lithium sorbent (lower temp, integration with shift)
- **Hand off promising technologies for more detailed modeling**
- **Assess additional technologies**
  - Water hydrate
  - Pressure swing absorption
  - solid sorbents

Key Assumptions

Capital Charge Factor (%)	14.5
Dollars (Constant)	2002
Plant Life (Years)	20
Coal Cost ($/ton Illinois #6)	28
Power plant Capacity Factor (%)	65
Pipeline Distance (miles)	50
Saline Injection Pressure (psia)	1,500